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(54) Control systems for multiple gas turbine-generator units

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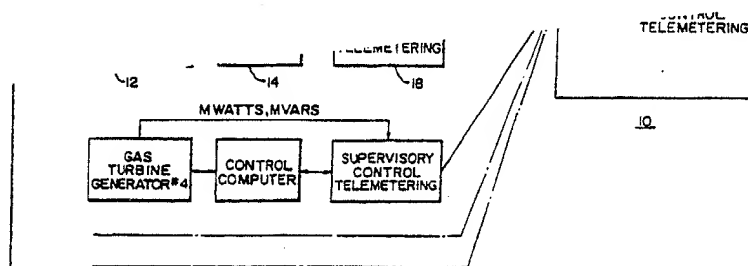
ERRATUM

SPECIFICATION NO 2007926A

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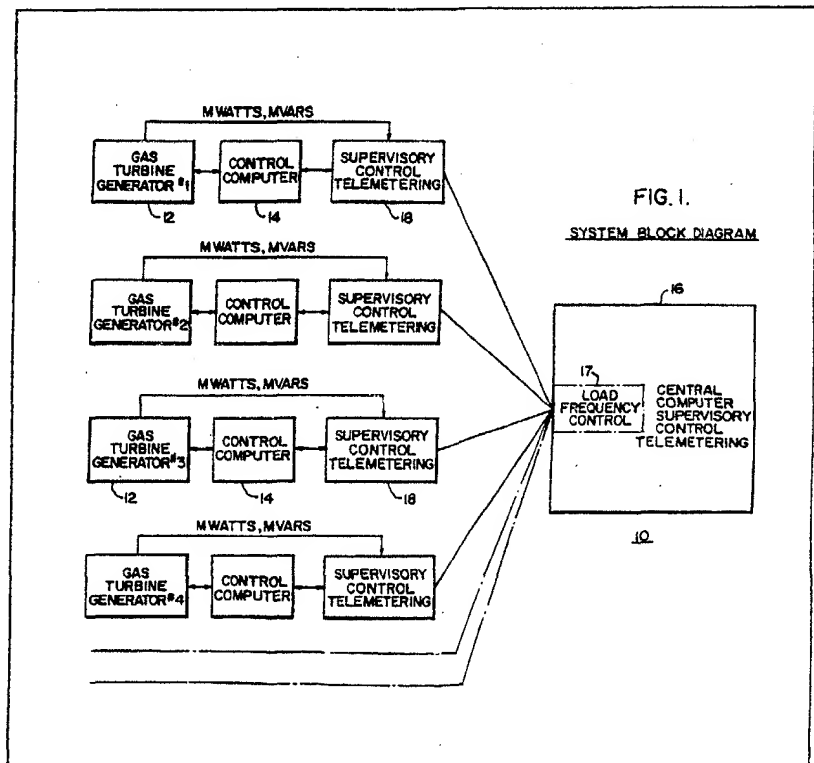
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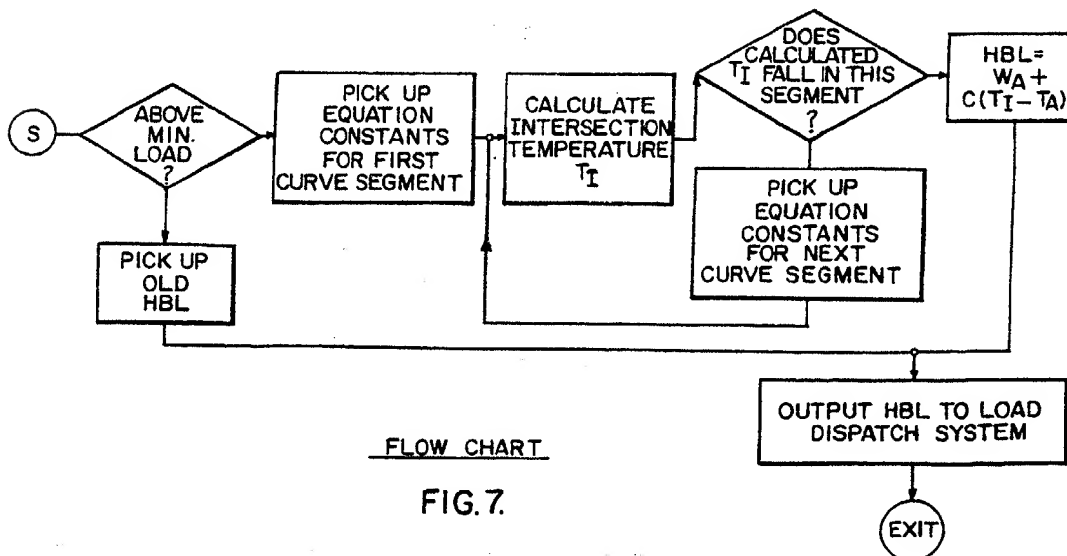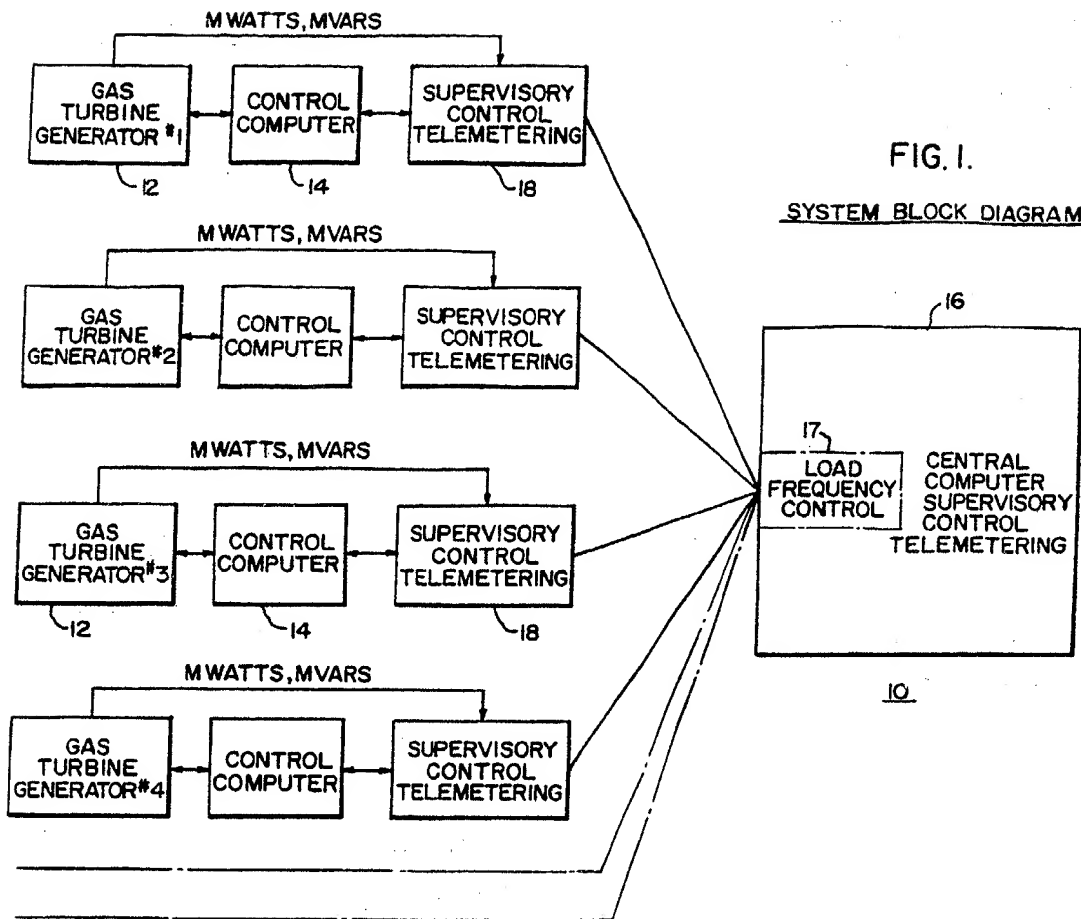23 October 1979

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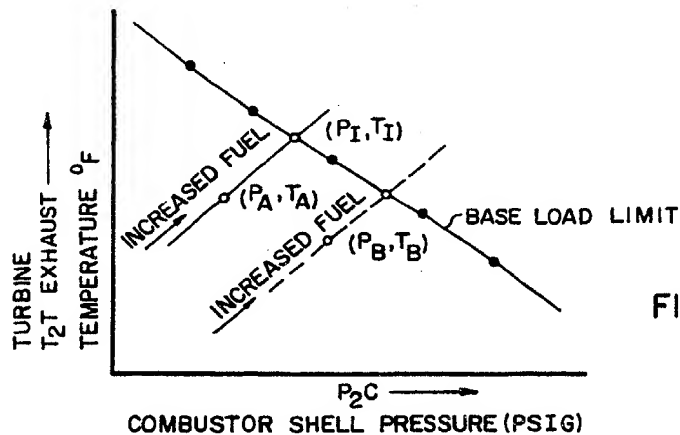(54) **Control systems for multiple gas turbine-generator units**

(57) A control system for multiple gas turbine-generator units 12 comprises a local control computer 14 which computes a maximum permissible output for each gas turbine-generator unit independently as a dynamic function of combustor shell pressure and exhaust temperature in that unit and the output thus obtained is transmitted to a central control 16. Load demands calculated for each unit are dispatched from the central control to individual local control arrangements 18 which respond to control their respective gas turbine-generators in a manner not to exceed the respective maximum output. Each turbine control 14 sets its generator output at a preset level which is modified by load change signals from the central control 16 and each control 14 operates its turbine fuel control to satisfy the load demand.

FIG. I.

SYSTEM BLOCK DIAGRAM

M WATTS, MVARS

GAS TURBINE GENERATOR #1	CONTROL COMPUTER	SUPERVISORY CONTROL TELEMETERING
12	14	18

M WATTS, MVARS

GAS TURBINE GENERATOR#2	CONTROL COMPUTER	SUPERVISORY CONTROL TELEMETERING

M WATTS, MVARS

GAS TURBINE GENERATOR#3	CONTROL COMPUTER	SUPERVISORY CONTROL TELEMETERING
12	14	18

M WATTS, MVARS

GAS TURBINE GENERATOR#4	CONTROL COMPUTER	SUPERVISORY CONTROL TELEMETERING

FIG. I.

<u>SYSTEM BLOCK DIAGRAM</u>

16

17 LOAD FREQUENCY CONTROL	CENTRAL COMPUTER SUPERVISORY CONTROL TELEMETERING

10

<u>FLOW CHART</u>

FIG. 7.

S → ABOVE MIN. LOAD ? → PICK UP EQUATION CONSTANTS FOR FIRST CURVE SEGMENT → CALCULATE INTERSECTION TEMPERATURE T_I → DOES CALCULATED T_I FALL IN THIS SEGMENT ? → HBL= W_A + C(T_I − T_A)

PICK UP OLD HBL

PICK UP EQUATION CONSTANTS FOR NEXT CURVE SEGMENT

OUTPUT HBL TO LOAD DISPATCH SYSTEM

EXIT

T$_2$T MW, P$_2$C

CONTROL COMPUTER

LOAD REFERENCE

MW CONTROL

<

TURBINE FUEL CONTROL

TURBINE GENERATOR SYSTEM

20

22

12

MODE LOGIC

TEMPERATURE LIMIT CONTROL

14

HBL COMPARATOR

INTERRUPT

CCI

CCO

DIGITAL POT

21

READY TO ACCEPT PULSES

HIGH BLOCKING LIMIT

AUTO DIGITAL SELECT

LOWER PULSE CONTACT

RAISE PULSE CONTACT

18

TURBINE HEALTH DISPLAY

LOCAL SUPERVISORY CONTROL/TELEMETERING

MW MVARS

CHANNEL TO CONTROL LOAD DISPATCH

FIG. 2.

TURBINE T$_2$T EXHAUST TEMPERATURE °F

INCREASED FUEL

(P$_I$,T$_I$)

(P$_A$,T$_A$)

INCREASED FUEL

BASE LOAD LIMIT

(P$_B$,T$_B$)

P$_2$C

COMBUSTOR SHELL PRESSURE (PSIG)

FIG.6.

LOGIC CONTROL PROGRAM

BLOCK BASE,PEAK SYS. RESV.
LOAD RAISE,LOAD LOWER
FAST RATE(501)EMERG. RATE(501)
EMERG. START (251) PUSH BUTT.
SELECT NORMAL RATE.

NOT → ZERO FRACTIONAL PULSE
COUNT(INTERRUPT PROGRAM)

LFDN ─┐
WASMD3(LOAD CONTROL MODE) ─┤
43R (REMOTE) ─┤ A
52GA(GEN. BKR.) ─┤
$\overline{5X}$ (NOT SHUTTING DOWN) ─┘

LFACT
(ACTIVE FLAG)(OLD CLBK RA)

LFACTC
(ACTIVE CCO)

FIG.3.

LOGIC CONTROL PROGRAM

MODE 3 ─┐
$\overline{ONSPD}$ (NOT ON ─┤
SPEED CONTROL) ─┤ A
LOWEST = KWOUPT ─┤
(LOAD CONTROL ─┘
OUTPUT LOWEST)

RAZOK(ACCEPT
RAISE PULSES)
(SIGN BIT OF
FRACT IN CONTROL
RES. TBL.)

FIG. 4.

LOGIC CONTROL PROGRAM

$\overline{LFLWR}$ ─┐
LFRAZ ─┤ A
RAZOK ─┘

INCREMENT LOAD REFERENCE
BY $\frac{2}{15}$ MW(501) $\frac{1}{15}$ MW
(251)(SAVE FRACTIONAL
COUNTS)

INTERRUPT ─┐
LFACT ─┤ A
LFON ─┘

LFRAZ ─┐
─┤ A
LFLWR ─┘

DECREMENT LOAD REFERENCE
BY $\frac{2}{15}$ MW(501) $\frac{1}{15}$ MW
(251)(SAVE FRACTIONAL
COUNTS)

ON ENTERING MODE 3(MW CONTROL)
FROM MODE 4(TEMPERATURE CONTROL)
SET WASMD3 FLAG & HOLD
EXISTING LOAD

FIG.5.

FIG. 8.

ECONOMIC DISPATCH RUNS
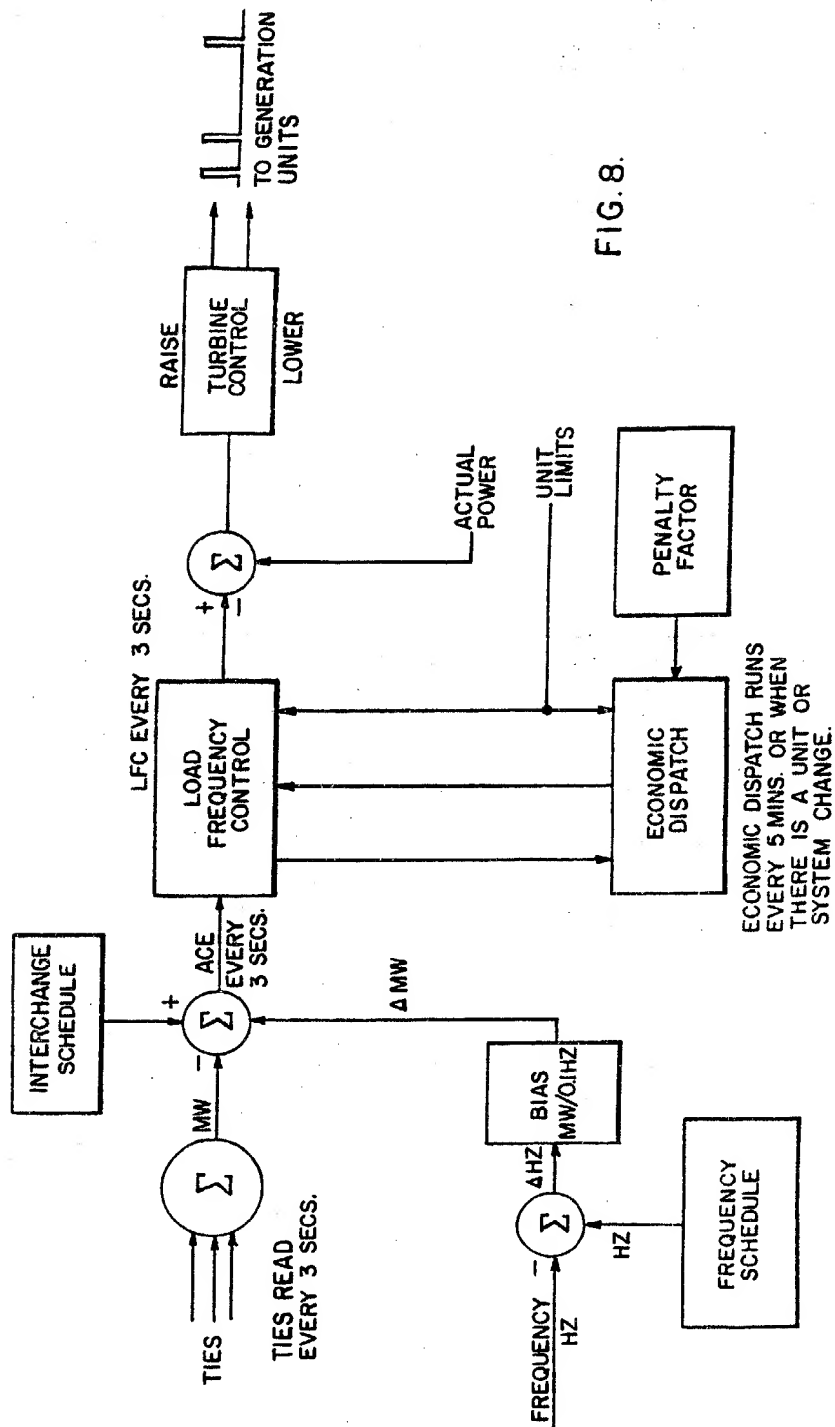EVERY 5 MINS. OR WHEN
THERE IS A UNIT OR
SYSTEM CHANGE.

SPECIFICATION

System for providing load-frequency control for multiple gas turbine-generator units

5   This invention relates to load-frequency control (LFC) and more particularly to systems arranged to execute LFC actions through gas turbine-generator units.

10   Load-frequency control is needed in power systems to hold frequency substantially constant as load changes occur. LFC is typically performed by a dispatch computer and the load changes needed to control the system frequency are dispatched to the
15   various plant locations for implementation by local plant controls.

         Gas turbine-generator units have been used to execute LFC commands to obtain better system response to load demands and more efficient use of
20   prime movers when used with or without steam turbine-generator units. For example, in the Jersey Central Power & Light system, LFC has been implemented through gas turbine-generator units. However, that implementation has been limited in
25   efficiency because of the manner in which allowable turbine load limits are calculated and implemented.

         It is an object of this invention to provide an improved load-frequency control system for multiple gas turbine-generator units with a view to over-
30   coming the deficiencies of the prior art.

         The invention resides in a load-frequency control system for a power system having a plurality of gas turbine-generator units, said control system comprising means for controlling the load level of each
35   of said gas turbine-generator units to satisfy a load reference applied thereto, means for generating the load references for the respective units to provide for substantially constant system frequency substantially without exceeding a high blocking limit for
40   each of said units, means provided for generating representation of turbine exhaust temperature and combustor shell pressure for each unit, and means for dynamically generating the high blocking limit for each of said units as a function of the turbine
45   exhaust temperature and the combustor shell pressure.

         The invention will become readily apparent from the following description of an exemplary embodiment thereof when read in conjunction with the
50   accompanying drawings, in which:

         Figure 1 shows a schematic diagram of a power system showing multiple gas turbines for use in LFC;

         Figure 2 shows a more detailed schematic of a
55   local control arrangement responsive to control supervisory signals;

         Figures 3-5 show block diagrams of logic functions employed in the load-frequency system of the present invention;

60   Figures 6 and 7, respectively, show a base load limit curve and a flow chart used in the computation of a high load blocking limit; and

         Figure 8 shows a basic flow chart for an LFC program used in the system.

65   More particularly, there is shown in Figure 1 a

power generation system 10 having a plurality of gas turbine-generator units 12 located at one or more plants within the area supplied by the system 10. Steam turbine-generator units are not shown, but a
70   number of such units are provided in the system 10 to meet base load requirements. Each gas turbine-generator unit 12 is provided with a conventional control system 14, in this case a digital computer control system.

75   A central supervisory control 16 includes a load/frequency control 17 and provides tieline interchange control and other control functions for the system 10. The control 16 includes conventional telemetering equipment for sending load dispatch
80   signals to respective remote local supervisory controls 18 associated with the respective gas turbine-generator units 12. Plant signals including megawatts and megavar signals are transmitted back to the central control 16 from the local controls
85   18 for load dispatch calculations and other purposes.

         A more detailed block diagram is shown for the local control arrangement in Figure 2. The control system 14 can be a conventional gas turbine computer control like that disclosed in U.S. Patent Applicat-
90   ion Serial No. 319,114, entitled "Improved System And Method For Operating Industrial Gas Turbine Apparatus and Gas Turbine Electric Power Plants Preferably With A Digital Computer Control System', filed by T. Giras et al. on December 29, 1972.

95   Basically, the computer control 14 responds to temperature, pressure, fuel and other plant feedback signals and to operator and central supervisory signals to control the turbine fuel and thereby the turbine speed and/or load. As shown, RAISE or LOWER
100 pulses are applied to a contact closure input system 21 by the local supervisory control 18 when the central supervisory control 16 has dispatched an increase or decrease in the local turbine load in order to control system frequency as the system electrical
105 load and/or power interchange with neighboring systems varies.

         A megawatt control 20, disclosed in the aforementioned Serial No. 319, 114, causes a fuel control 22 to change the fuel flow to a level which satisfies the
110 megawatt load level setpoint as it is changed by incoming supervisory increase or decrease pulses. Normally, each supervisory pulse represents a demand for a load change equal to a predetermined number of megawatts.

115   To provide faster, more efficient and generally better system frequency control, the system 10 determines how much load each gas turbine-generator unit 12 can provide on the basis of its current operating condition. The system thus dynamically deter-
120 mines allowable loading on each turbine 12 in accordance with the physical health of the turbine and in accordance with ambient variables. Thus, as ambient conditions vary, and as gas turbine combustion efficiency, turbine blade performance, com-
125 pressor fouling and other turbine health variables change with time, a high blocking limit, i.e., the turbine load capability, is continuously redetermined as a function of compressor discharge pressure and turbine-exhaust temperature and transmitted to the
130 central supervisory control 16 where load com-

mands are calculated and dispatched to the gas
turbine-generator units 12 on the basis of the respec-
tive high blocking limits. The respective gas turbines
12 move under local megawatt control th the dis-
5   patched load levels which are either at or below the
respective high blocking limits, thereby normally
achieving load/frequency control quickly on a feed-
forward basis without incurring local trim action by
exhaust temperature limit control. Thus, the use of
10 the calculated high blocking limit for each turbine 12
in the dispatch calculations assures that the dis-
patched load for each gas turbine 12 will not exceed
its high blocking limit, and further that each turbine
12 will not exceed its exhaust temperature limit
15 when it is dispatched to move to a higher load no
greater than its high blocking limit. With the use of
the gas turbines 12 for frequency control, better sys-
tem response and efficiency are realized as com-
pared to the use of steam turbines for frequency con-
20 trol.
    As an example, a gas turbine-generator unit may
normally be capable of generating 100 MW at 80°F or
80 MW at 105°F. Once the turbine has been in use for
some time, its physical state may be such that at
25 105°F it can only generate no more than 65 MW
without exceeding exhaust temperature limits. With
the control system disclosed herein, the reduced
turbine operating capability is reflected as a
dynamically calculated and reduced high load block-
30 ing limit which prevents the dispatch of over-limit
load increases that cannot be met by that turbine.
    An additional feature of the system is that it can
include a turbine health monitor, i.e., a display which
compares the current high blocking limit (HBL) to the
35 rated or normal high blocking limit at the current
ambient conditions. For this purpose, the local com-
puter can keep in storage a curve representing the
HBL values for the turbine at the start of life, i.e., HBL
as a function of turbine exhaust temperature. In the
40 alternative, the curve can be HBL as a linear function
of compressor inlet temperature (see infra) as of the
start of turbine life. The computer generates outputs
corresponding to the actual and the stored HBL
value for display.
45 To place an individual gas turbine-generator 12 in
the load/frequency control mode, the operator
pushes an Automatic Dispatch push button, and
computer control logic operations are initiated as
shown in Figure 3. If the turbine had been in temper-
50 ature control, it is switched to megawatt control
(Mode 3) and the load reference is set to a preset
level below the high blocking limit to allow some
range for frequency regulation. A block is placed on
certain operations such as base mode, peak system
55 reserve mode, manual load raise or lower, etc. as
shown in Figure 3. As shown in Figure 4, computer
logic operations allow acceptance of dispatch raise
or lower pulses, and Figure 5 shows the logic emp-
loyed in the computer to process raise or lower dis-
60 patch pulses as received. Each pulse signifies a fixed
megawatt change and the load reference for the
megawatt control is adjusted accordingly.
    In the prior art, a static high blocking limit has
been determined from compressor inlet tempera-
65 ture. Thus, the prior art high blocking limit is based

on the decrease in rated megawatts as the compres-
sor inlet temperature increases. This temperature
(T_1T) is measured and the high blocking limit is gen-
erated as a linear function of T_1T. Since it is a static
70 calculation, the line must be adjusted from time to
time to take into account factors like turbine aging,
change of fuel and, to a lesser extent, change in
barometric pressure.
    In accordance with a preferred embodiment of the
75 present invention, a high blocking limit is calculated
dynamically to provide better system efficiency.
Thus, as fuel in increased, combustor shell pressure
and exhaust temperature increase in approximately
a linear fashion. So that the design value for turbine
80 inlet temperature is not exceeded, the maximum
allowable exhaust temperature is defined by a load-
ing curve as a function of combustion shell pressure.
The loading curve is approximated as four straight
line segments as shown in Figure 6. Curves allowing
85 higher turbine inlet temperatures at a cost of higher
maintenance costs are available but only the lowest
or base load curve is shown.
    In Figure 6, there is shown a plot of the base load
curve and a loading line, the locus of points plotting
90 exhaust temperature (T_2T) vs combustor shell pres-
sure (P_2C) as fuel is varied. The point where the two
intersect (P_1T_1) is the point where base load is
reached and temperature control limits further
increase. If other ambient temperatures and/or other
95 turbine efficiency conditions exist, a different but
essentially parallel loading path through (P_BT_B) is fol-
lowed (dotted line) giving a different intersection.
The slope of the loading line is characteristic to the
turbine and is empirically determined. Since there is
100 good correlation between change in exhaust temp-
erature and change in megawatts, calculating the
temperature at the intersection gives the maximum
allowable increase in exhaust temperature. The
available increase in megawatts can be predicted
105 from the present megawatts, the combustor shell
pressure and the exhaust temperature and the max-
imum allowable exhaust temperature increase.
    The present megawatts plus the available increase
in megawatts becomes the high blocking limit which
110 is telemetered to the central load dispatch system.
Figure 7 shows a flow chart for the described basic
logic operations performed in calculating HBL.
    From knowledge of the present operating condit-
ions P_A, T_A and W_A (megawatts), the intersection
115 temperature can be shown to be calculated as $T_1 = d$
$T_A + e P_A + f$ where d, e, and f are constants. Since
different constants are needed for each loading
curve segment, there are four sets of constants d_n,
e_n, f_n where n = 1, 2, 3 and 4. A calculation is made
120 for the one set of constants and if T_1 does not fall in
the first segment, calculations are made for succeed-
ing segments until the actual intersection on the
segment matching the constants is found. From
there, the high blocking limit is calculated as HBL =
125 $W_A + C(T_1 - T_A)$ where C is a constant.
    Calculations update the HBL at regular intervals
anytime the unit is above a predetermined load level
such as minimum load. The low blocking limit can be
calculated locally or remotely for narrow band limit-
130 ing as either LBL = a, or LBL = HBL − a_2 or LBL =

$N_3(HBL)$ where a_1, a_2 are constants. For wide band limiting, LBL can be made equal to the minimum load value specified for the turbine.

The following calculations are used to determine constants needed to predict allowable increase in exhaust temperature, hence megawatts.
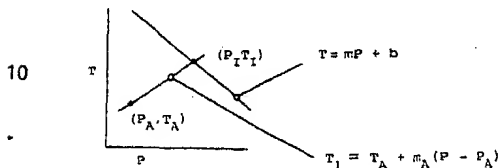
at intersection, $(P_I T_I)$

$$mP_I + b = T_A + m_A (P_I, P_A) = T_A + m_A P_I - m_A P_A$$
$$mP_I - m_A P_I = T_A - m_A P_A - b$$
$$P_I (m - m_A) = T_A - m_A P_A - b$$

$$P_I = \frac{T_A - m_A P_A - b}{(m - m_A)}$$

$$T_I = mP_I + b$$

$$T_I = \frac{m}{m - m_A} (T_A - m_A P_A - b) + b$$

$$= \frac{m}{m - m_A} (T_A - m_A P_A) - \frac{m b}{m - m_A} + b$$

$$= \frac{m}{m - m_A} (T_A - m_A P_A) + \frac{-m_A b}{m - m_A}$$

$$= \frac{m}{m - m_A} (T_A - m_A P_A - \frac{m_A b}{m - m_A}$$

$$T_I = \frac{m}{m - m_A} T_A - \frac{m m_A}{m - m_A} P_A - \frac{m_A b}{m - m_A}$$

$$= d T_A + e P_A + f$$

At the dispatch computer 16, the LFC program computes load changes needed for frequency control and schedules load changes for individual units 12 to satisfy the total load change requirement within the constraints of the HBL values received from the various units 12. In Figure 8 a general block diagram is shown for an LFC sub-system.

AREA CONTROL ERROR (ACE)

The Area Control Error (ACE) program calculates the control error which the AGC system must minimize. To provide better control action, a controller algorithm is used on the ACE value to provide a smoothed, predicted, and compensated ACE. This value is used by the LFC program to regulate the generating units.

The area control error is the change in generation necessary to meet scheduled frequency and scheduled net interchange. The sign convention is as follows:

Positive = Excess generation, power flow out of area.

Negative = Deficiency in generation, power flow into area.

The equation is:

$$E_A = P_T(1) - P_S + B (F - F_S)$$

where:

$P_T(1)$ = Flow on tie 1
P_S = Net Scheduled Interchange
B = Frequency Bias
F = System Frequency
F_S = Scheduled Frequency

Provision is made for considering different modes of control in the calculation.

LOAD FREQUENCY CONTROL PROGRAM

The purpose of the Load Frequency Control (LFC) Program is to calculate and assign megawatt output required from each generating unit to satisfy operating area control needs. The program uses several input values describing the current power requirement and the status of the generating units, and then determines each unit's assigned power. The power assignment is calculated according to the unit's economic point as decided by the Economic Dispatch Control (EDC) Program or the operator.

The power difference between the economic operating point and the total required power for the area is calculated. This power deviation is distributed to the various units according to a unit participation factor and the dynamic limits of the individual units. Each unit's economic operating point is then adjusted to absorb the power deviation to satisfy the total power requirement. However, if the sum of the participation factors is not 100 percent, or one or more units have exceeded the unit's allowable dynamic limits (as calculated in accordance with the present invention), the total power generation requirement may not be satisfied in the first assignment pass. In such cases, the LFC program adjusts the total power deviation and attemps to redistribute the power deviation to those units which can still handle it. Several iterations may be required, terminating when the difference between the generated and the required power is less than some acceptable error. Should the program fail to achieve total power within a fixed number of iterations, a nonconvergence alarm is initiated.

The program also checks the changes in certain system parameters over prescribed time intervals. If these changes become excessive, a new Economic Dispatch calculation will be made. This will also apply if a unit is added to or deleted from those being direct digitally controlled.

The basic function of the LFC can be stated as follows:

Power to be assigned = the sum of actual power of all BASE or AUTO minus smoothed and predicted area control error.

Regulating Power = power to be assigned minus the base settings of units on BASE or AUTO.

ECONOMIC DISPATCH CALCULATION PROGRAM

The function of the Economic Dispatch Control (EDC) Program is to calculate the economic loading

point for the various generating units. The results of
this calculation are used by the Load Frequency Con-
trol (LFC) Program to regulate the power assignment
based on the economic loading points to satisfy the
5 area requirement. The results of the Pass II calculat-
ion are used by the operator to manually control the
generating units in the fixed load mode.
    To save running time, the program consists of two
separate routines. The first calculates the incremen-
10 tal cost curve anytime pertinent parameter changes.
Incremental heat rate curves are stored on RAD in
the form of line segments (slope-intersect). This
routine is run anytime the fuel cost has changed, or a
heat rate curve has been modified. The fuel costs are
15 modified via the dispatch console.
    The second routine is the normal EDC economic
loading calculation. A trial value of Lambda is
assumed and each cost curve is entered to obtain the
designed power. If the sum of the assigned power
20 equals the required value within a specified bound-
ary, the value of Lambda is correct and the solution
is valid. If not, Lambda is increased or decreased and
the numerical process is continued until the error
criteria is satisfied. A binary search procedure is
25 used to ensure rapid convergence and minimum
running time. If the assigned power is outside the
specified limits, it is set equal to that limit. If the
required power cannot be reached within the limit
calculated as described herein for the various units,
30 an alarm message is output and no results are stored
for the LFC program.
    EDC is normally requested to execute at regular
intervals. However, the program may also be
requested by either the LFC Program or the operator.
35 LFC bids indirectly for the EDC Program whenever
the system operating point has drifted too far from
the economic operating point. The operator may
request EDC whenever the economic loading points
of the generating units must be updated.
40   EDC calculates the economic loading points for
each generating unit placed on AUTO control. The
economic calculations are based on the principles of
Incremental Loading, to achieve minimum overall
fuel costs for a given System demand. The calculat-
45 ions recognize the most limiting unit constraints,
unit fuel costs, and transmission loss penalty factors.
    EDC dispatches a total system load, determined by
LFC, among the available units. The program runs as
requested on the basis of time, and/or megawatts
50 change, and/or a flag due to an operator request. The
desired power is obtained from LFC and the results,
the desired power for each unit, are stored for LFC
for consolidation.
TURBINE CONTROL PROGRAM AND PULSE TO
55 *SUPY ROUTINE*
    The function of the Turbine Control Program is to
compute unit error and the required control action in
terms of raise or lower pulse rates. Turbine control
action is computed every four seconds, but the res-
60 ponse to a pulse rate by a typical turbine extends
over several four second periods. It is therefore
necessary to prevent the over-correction which
would result if pulsing were based only on instan-
taneous error. The possibility of using faster pulse
65 rates is ruled out. They are detrimental to the speed

of response and, thus, to regulation of the power
system; and they also cause excessive thermal cycl-
ing in the gas turbine.
    In the use of the mode feedback (anticipation), a
70 simple model of the turbine is employed to antici-
pate changes in generation. The model used is a
simple exponential decay, such that if correctly
adjusted, the sum of actual plus anticipated power is
constant.
75   The equations used in the program are:

$$ANTIC(N) = ANTIC(N-1) * DECAY$$
$$ERROR = DESP - (ACTP + ANTIC(N))$$
$$ANTIC(N) = ANTIC(N) + ERROR$$
80 $$PULSE = ERROR * CONV$$
where:
    DESP   = Desired Power (Setpoint from
                (LFC)
    ACTP   = Actual Power (Feedback from
85   REDAC 70 data point)
    ANTIC   = Anticipated Change in Actual
                Power from previous pulse(s)
    DECAY   = Exponential Decay in 4 sec.
    CONV   = Pulses/MW
90 PULSE   = Output Pulse Rate
ANTIC is the anticipation term and
represents the effect on the unit still
to be produced by the previous pulses.
    The first equation above shows how much ANTIC
95 should have changed in the 4 sec. since the last
pulse rate due to the response of the unit over time.
The third equation above gives the total movement
of the unit (occurring over a few control cycles) due
to the pulse rate output previously and the pulse rate
100 now about to be output.
    For the model feedback rate to be effective, it is
important that the CONV term represent an accurate
conversion of pulse rate to megawatt error and that
the DECAY term correspond to the actual dynamics
105 of the turbine. While these terms are not constant
over the entire range of turbine output, sufficient
accuracy can be obtained by using a DECAY which is
average over typical operating range, and CONV at
the most responsive region.
110   The sustained rate of change of a controlled unit is
limited by the Turbine Control program. The pre-
determined maximum sustained (thermal recovery)
rate is stored for each unit as RATE in MW per 4
seconds. The rate limiting is machanized by model-
115 ing the available step change of the gas turbines.
When a pulse is sent out, the program considers that
the available step has been reduced and that it will
return to normal at the sustained rate of change des-
cribed above. Although this use of available step as a
120 physical entry applies only to increase in turbine
output, it is used mathematically to limit changes in
either direction.
    In the computation of pulses, the available step
(QADN, QAUP) is taken out as follows:
125   MAX RAISE PULSE = QAUP (Positive)
        MAX LOWER PULSE = QADN (Negative)
The magnitudes of QAUP and QADN build up to
QMAX so that when no available step has been
used, a step of QMAX (in MW) can be made in either
130 direction. QMAX, then, is the maximum instantane-

ous change capability of the turbine-generator com-
bination. The available step is updated each control
cycle, after the development of pulses and the cal-
culation of anticipation.

5   CLAIMS
1.   A load-frequency control system for a power
system having a plurality of gas turbine-generator
units, said control system comprising means for
controlling the load level of each of said gas
10   turbine-generator units to satisfy a load reference
applied thereto, means for generating the load refer-
ences for the respective units to provide for substan-
tially constant system frequency substantially with-
out exceeding a high blocking limit for each of said
15   units, means provided for generating representation
of turbine exhaust temperature and combustor shell
pressure for each unit, and means for dynamically
generating the high blocking limit for each of said
units as a function of the turbine exhaust tempera-
20   ture and the combustor shell pressure.
2.   A load-frequency control system as set forth in
claim 1 wherein a low blocking limit is also gener-
ated for each gas turbine-generator unit for imp-
lementation through said load reference generating
25   means.
3.   A load-frequency control system as set forth in
claim 1 or 2 wherein a central load dispatch compu-
ter includes load-frequency control means for
generating load increase-decrease signals for the
30   gas turbine-generator units, each of said gas
turbine-generator units includes a local control sys-
tem including said load level controlling means and
said high blocking limit generating means, and
means are provided for transmitting signals repres-
35   enting the high blocking limits to said dispatch com-
puter and the load increase-decrease signals to said
local control systems.
4.   A load-frequency control system as set forth in
claim 1, 2 or 3 wherein health monitor display means
40   are provided for comparing the dynamically deter-
mined high blocking limit with a stored expected
value for the high blocking limit at the measured
turbine exhaust temperature and existing ambient.
5.   A load-frequency system as set forth in claim
45   1, 2, 3 or 4 wherein means are provided for generat-
ing a representation of actual megawatts for each
unit, the high blocking limit is dynamically deter-
mined for each unit by adding measured megawatts
to available increase in megawatts, and the available
50   increase in megawatts is determined for each unit as
the intersect of a stored characteristic temperature
limit versus combustor shell pressure loading curve
for the gas turbine and a loading line having a pre-
determined slope and extending from the measured
55   exhaust temperature value through the characteris-
tic temperature limit curve.
6.   A load-frequency control system substantially
as described hereinbefore with respect to, and as
shown in, the accompanying drawings.